The *Class* Act

DOE's Reservoir Class Program Newsletter

Volume 6/1

Winter 2000

U. S. Department of Energy ♦ National Petroleum Technology Office ♦ P. O. Box 3628 ♦ Tulsa, OK 74101-3628

Simulation of CO_2 Flooding in Small Algal Mounds Demonstrates Cost-Effectiveness in Increasing Oil Recovery

By William Culham, REGA, Inc; Douglas M. Lorenz, Texaco, E&P (formerly of REGA); and Thomas C. Chidsey, Jr., Utah Geological Survey

Phase I for this DOE Class II project, entitled "Increased Oil Production Utilizing Secondary/Tertiary Recovery Techniques on Small Reservoirs in the Paradox Basin, Utah," was designed to characterize five shallow-shelf carbonate reservoirs in the Pennsylvanian (Desmoinesian) Paradox Formation and choose the best candidate for a pilot demonstration for either a waterflood or carbon dioxide (CO_2) flood project. Phase I also included reservoir simulations, economic assessments, and recommendations for Phase II, which will be a pilot CO_2-flood field demonstration. Phase I was completed August 31, 1998. Phase II began on September 1, 1998, and will run through August 31, 2002. The Phase II field demonstration, monitoring of field performance, and associated validation activities will take place in the Paradox Basin of southeastern Utah within the Navajo Nation.

Project Background and Summary

The principal objectives of the study are to develop detailed quantitative descriptions of shallow-shelf carbonate buildups (algal mounds) and use these descriptions, coupled with composition simulation, to predict the performance of the reservoirs in the mound complexes under three different reservoir recovery processes. The three processes are: primary depletion, CO_2 flooding, and waterflooding. The economic feasibility of implementing one or more recovery processes was also investigated.

Compositional simulation studies were conducted for Anasazi and Runway Fields (**Figure 1**). The results indicate that CO_2 flooding is the only technically feasible recovery process suitable for these reservoirs. Based on this conclusion, CO_2-flood implementation costs were developed. Implementation costs in conjunction with reservoir production and injection performance predictions were used to complete a suite of economic assessment studies. One of the CO_2-implementation options studied provided the best economic return: a continuous CO_2-injection case utilizing reinjection of unprocessed produced gas, a leased main injection compressor, and DOE cost share. This option in the Anasazi Field provides a before-tax net present value (NPV) of more than $5.9 million using a 10 percent discount rate, and a before-tax rate of return (ROR) of 32 percent on a total investment of $2.7 million. The profitability index (PI) of this particular implementation was determined to be 10.4 to 1.0. For Runway Field, before-tax NPV, discounted at 10 percent per year, is more than $3.1 million, and the before-tax ROR is 30 percent on a total investment of $2.79 million. The PI of this particular implementation was determined to be 5.0 to 1.0.

The study's predicted CO_2-flood responses, and the associated economics, support the extension of the overall shallow-shelf carbonate evaluation program to Phase II.

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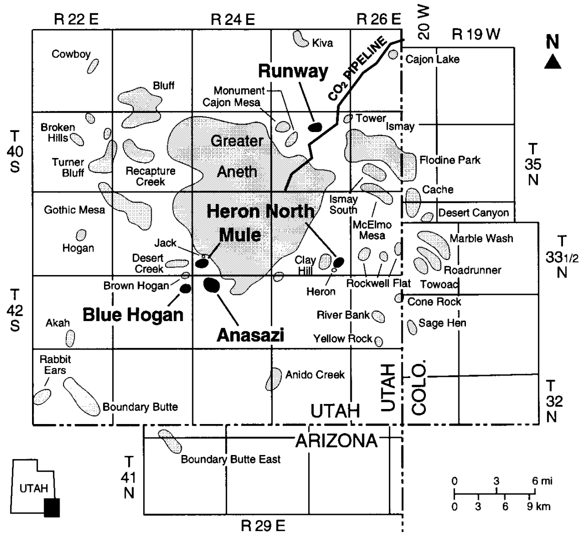

Figure 1 Location of project fields (dark shaded areas with names in bold type) in southwestern Paradox Basin in the Navajo Nation, San Juan County, Utah.

Reserve and Recovery Determinations for Project Fields

Primary recovery and original oil in place (OOIP – **Table 1**) were determined for the project fields from volumetric reserve calculations, material balance calculations, and decline curve extrapolations, as well as refined geologic characterization. These volumetric calculations were made by evaluating well logs and reservoir areal extent (as defined by seismic reflection data), coupled with reservoir geometry. Material balance and decline curve calculations utilized the field's production and pressure histories. Knowing the OOIP and the primary recovery, the amount of oil left behind was calculated. Lastly, utilizing the results from the simulation studies of Anasazi and Runway Fields, sweep efficiencies for CO_2 flooding and the ultimate enhanced recovery were estimated for all project fields (**Table 1**). Using the average predicted oil recovery of 71.8 percent (percent recovery of oil remaining in place after primary recovery) for the Runway and Anasazi reservoirs, the projected addition to reserves if CO_2 is also applied to project fields is over 8.2 million stock tank barrels (STB) of oil.

Economic Assessment of CO_2 Flood, Anasazi Field

Phase II will implement and complete a CO_2 flood in the Anasazi reservoir. Using reservoir-

Table 1 Reserve and Recovery Determinations

Project Field	OOIP* (MSTB)	Primary Recovery		ROIP** (MSTB)	CO_2 Flood Projected Recovery (MSTB)	CO_2 Flood Recovery % ROIP
		Oil (MSTB)	Gas (MCF)			
Anasazi†	4,706	2,000	1,890,000	2,706	2,208	81.6
Blue Hogan	2,530‡	321	968,000	2,209	1,586	71.8
Heron North	2,640‡	216	2,650,000	2,424	1,740	71.8
Mule	2,000‡	454	288,000	1,546	1,110	71.8
Runway	3,372	825	2,830,000	2,547	1,577	61.9

*Original oil in place (thousand stock tank barrels [MSTB]), mound-core and supra-mound intervals (includes platform interval in Runway)

** Remaining oil in place

† High-rate case starting CO_2 flood January 1, 2000

‡ Estimate based on approximate volumetric data

simulation-based performance predictions and current CO_2-flood implementation costs, detailed economic assessments were conducted for a number of different CO_2-flood options. These sets of studies indicated that:

1. A CO_2 flood of the Anasazi reservoir has robust economics. With DOE participation, the project would have a ROR of 62 percent, a payout of 35 months, a PI of 15 to 1, and a discounted (10 percent) NPV in excess of $12.5 million. Even without DOE participation, the economics remain robust with a ROR of 48 percent, a payout of 39 months, a PI of 8 to 1, and a discounted NPV of over $11.0 million. The capital requirements would be $3.146 million.
2. Leasing the compressor on a five-year contract basis is better economically than purchasing the compressor. Leasing improves the NPV by approximately $1 million.
3. The benefit from separating CO_2 from the produced gas so the hydrocarbons can be used for fuel and sales is offset by the large capital investment required for a CO_2 membrane separation facility. Thus, reinjection of all produced gas without processing is economically more attractive than implementing a CO_2 flood with gas processing.
4. The difference between minimum and maximum cost options for installation of flow/injection lines and the CO_2 supply is approximately $1.0 million; however, the economics are positive for both options. With DOE cost sharing, the ROR is 56 percent with a PI of 11.5 to 1.
5. The ROR and PI are not significantly different for a process using blowdown after six years of CO_2 injection versus the continuous CO_2 injection case. However, the NPV is substantially less with blowdown (approximately $1.4 million). The lower NPV is a result of lower oil recovery for the blowdown case (800,000 STB less than the continuous injection case).

Production data and injection gas requirements, including CO_2 make-up purchases, were used to assess the financial merits of a CO_2 flood with a total injection rate of 8 million cubic feet of gas per day commencing January 1, 2000. The economic assessment, using two compressor options, was conducted assuming the following conditions: (1) leased compressor (option 1, $19,500; option 2, $23,500 [same compressor with a different engine]), (2) CO_2 supply line construction using the minimum costs option ($825,000), (3) no gas processing, and (4) cost sharing by DOE. This assessment demonstrates that CO_2 flooding provides both an adequate flood response with either of the compressor options, an acceptable economic ROR of 32 percent, and a payout of 36 months. A discounted (10 percent) NPV of $5.9 million could be realized by implementing a CO_2 flood under the proposed conditions.

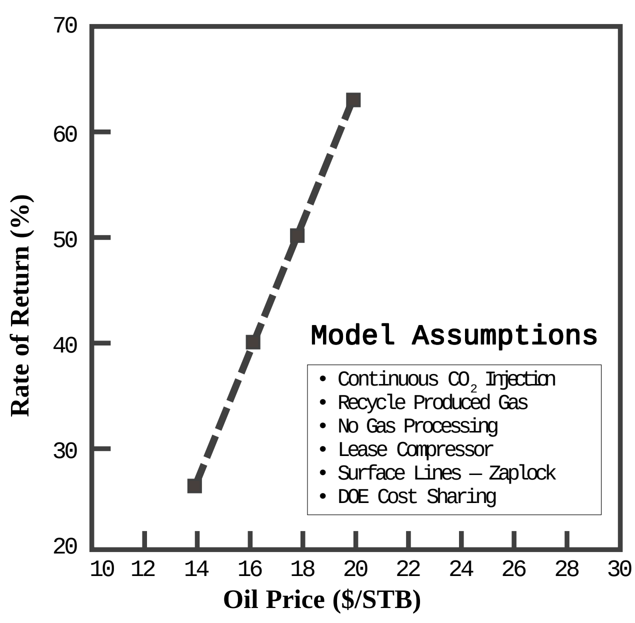

Figure 2 Rate of return versus price of oil, Anasazi Field CO_2 flood, at high rate.

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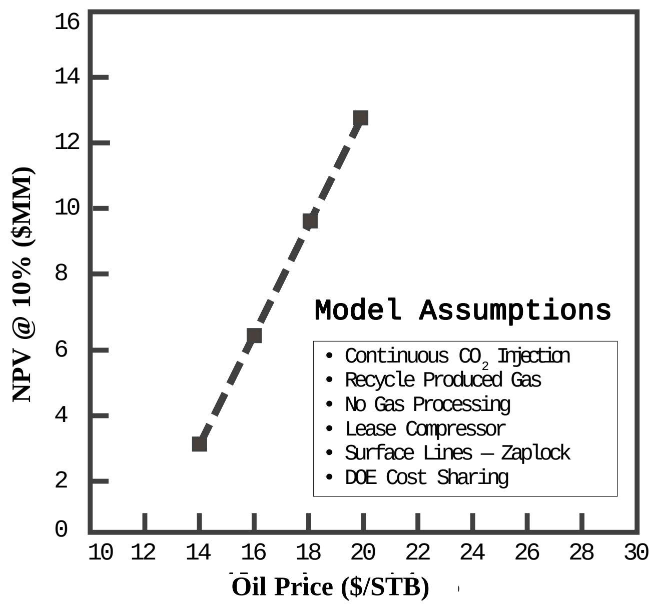

Figure 3 Net present value versus price of oil, Anasazi field CO_2 flood, at high rate.

If the CO_2 flood performs as predicted, it is a financially beneficial process for increasing the reserves of the Anasazi reservoir; however, the ROR and NPV are very sensitive to oil prices (**Figures 2 and 3**). Therefore, the economic assumption should be recalculated before installation of injection facilities.

Recommendations

Based on the results of the completed geologic study, reservoir performance predictions, and the associated economic assessment of implementing a CO_2 flood in the Anasazi reservoir, the following production scenario is recommended:

1. A CO_2-injection project should be implemented in the Anasazi reservoir.
2. A field injectivity test using CO_2 should be conducted on the Anasazi No. 6H-1 well, a project well in the western part of the field, to establish long-term injection rate data before committing to further Phase II work.
3. After the CO_2 source is obtained for Anasazi Field, the economic assumption should be recalculated to see if the project is still economically feasible at current prices.
4. The main injection compressor should be leased rather than purchased to provide the most operating flexibility and least financial risk.
5. Produced gas processing is not required for a single-field CO_2-flood implementation case. It is not required from a reservoir processing standpoint, nor is it justified economically.
6. Horizontal well injectivity should be predicted from the appropriate well-test models after calibration with vertical well-test data.

Conclusions

Phase I of the project showed that a CO_2 flood was technically superior to a waterflood and was economically feasible. For Anasazi Field, an optimized CO_2 flood is predicted to recover 4.21 million STB of oil. This represents an increase of 1.65 million STB of oil over predicted primary depletion recovery by January 1, 2012. The projected 4.21 million STB of oil production represents about 90 percent of the OOIP in the mound complex and 37 percent of the OOIP of the total system modeled.

The field demonstration will include: conducting a CO_2 injection test(s), obtaining a CO_2 source and fuel gas for the compressor, recalculating project economics, drilling a development well(s) (vertically or horizontally), purchasing and installing injection facilities, monitoring field performance, and validation and evaluation of the techniques. Such a demonstration should prove (or disprove) CO_2-flood viability, and thus help determine whether the technique can be applied to numerous small carbonate-buildup reservoirs in the Paradox Basin and similar reservoirs in other basins throughout the U.S.

Integrated Approach to Improve Waterflooding Performance of a Marginal Oil Field

By Mohan Kelkar
The University of Tulsa

The Glenn Pool Field, a field which has been producing for over 90 years and which has been subjected to water flooding since 1956, was selected for improving its production through various technologies under DOE's Class I Program. The project was divided into two budget periods. Overall, the technologies that proved to be effective include: integrated approach to describe reservoirs, geological description using discrete genetic intervals (DGIs), use of productivity index to grade various parts of the reservoir, geostatistics, and flow simulation. The technologies which proved to be only marginally effective or ineffective include: use of microresistivity logs for detailed geological description, cross borehole tomography, and drilling of deviated holes using a surface steered drilling assembly.

Background

The Glenn Pool Field is located in portions of Tulsa and Creek Counties of Oklahoma. The field was discovered in 1905, and it is estimated as having produced 330 million barrels of oil (MMBO) from the Middle Pennsylvanian (Desmoinesian) age Bartlesville Sandstone. Glenn Pool Field, like other fields developed in the Bartlesville Sandstone, is located on the Northeastern Oklahoma Platform. **Figure 1** shows the area of study for this project. The Self Unit indicated in the figure was the subject of first budget period investigation, whereas the gray area surrounding the Self Unit was the subject of the second budget period.

Budget Period I

In the first budget period, our effort concentrated on the Self Unit, a 160-acre unit, located in the southeast portion of the Glenn Pool Field (see **Figure 1**). This unit, with original oil in place of 13 MMBO, has so far produced about 21 percent of OOIP. We applied several new technologies to improve the reservoir description of this unit. These technologies included integration of geological, geophysical, and engineering data, geological description using DGIs, modern logs, cross borehole tomography, geostatistics, and reservoir flow simulation.

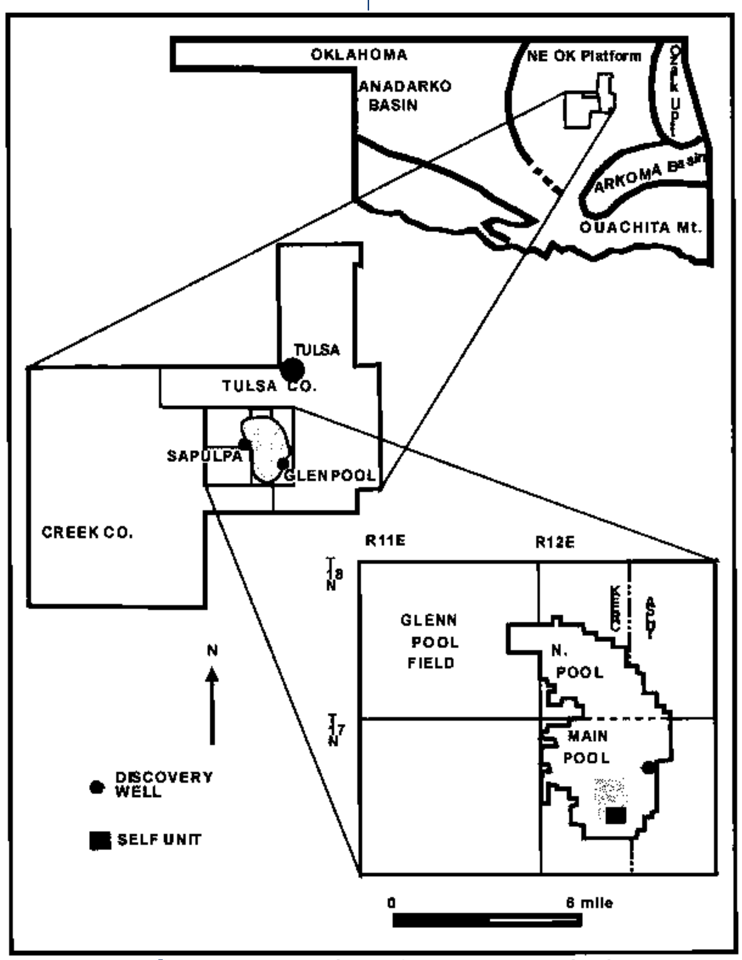

Figure 1 Location of Glenn Pool Field.

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Very limited core and log data were available from the unit. To compliment the existing information, a new vertical well was drilled, and additional core data as well as modern suite of logs, including micro borehole imaging, were acquired on a new well. Using the newly drilled well as a source well, three cross borehole seismic surveys were conducted. With the help of updated geological models as well as cross borehole seismic data, a detailed reservoir description was constructed and, using a commercial flow simulator, various scenarios were investigated to improve the performance of the field. The cross borehole data did not add significant new information. A combination of recompletion and stimulation of most wells followed by increasing the water injection rate in the field was observed to be the most optimal change to improve the flow performance of the Self Unit.

The proposed reservoir management plan was implemented, and the unit performance was monitored for more than three years. At the base level, the Self Unit was producing between 15 to 17 bbl/day. The initial increase in the incremental oil production was predicted to be in the range of 15 to 32 bbl/day (see **Figure 2**). The cases in **Figure 2** represent the use of different relative permeability curves. The same figure also shows the actual production. As can be seen, the actual production fell within the predicted uncertainties. In short, we were able to correctly predict the performance of the reservoir. Although in terms of actual production, this increase is not much, note that it still represents about a 150 percent increase in the production. Further, the field is more than 90 years old and has been subjected to many technologies in the past. If we can cost-effectively increase production from such a mature field, we should be able to do better in other, relatively younger fields. The economic evaluation indicated finding cost of oil is in the range of \$4.80 to \$6.00 per barrel. This cost can be reduced substantially (to about \$2 to \$3 per barrel) if we use only the cost-effective technologies and eliminate the use of other technologies.

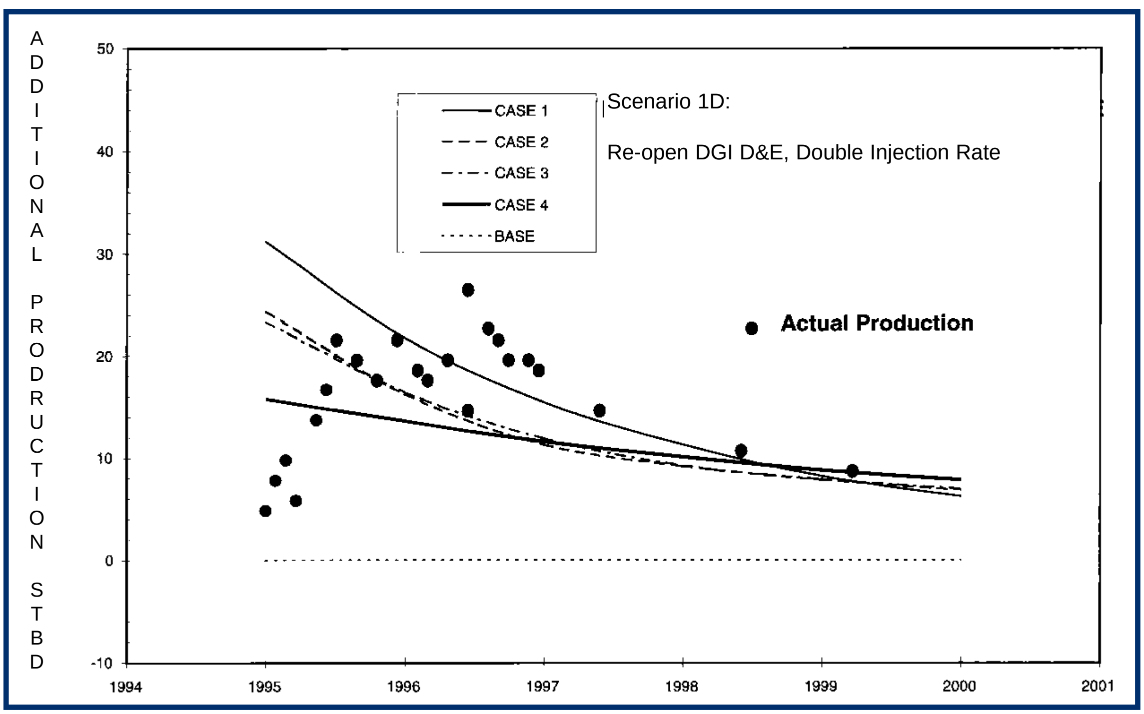


Figure 2 Incremental production rate for the Self-Unit for various cases.

BUDGET PERIOD II

In Budget Period II, we extended our efforts to other parts of the Glenn Pool Field (see **Figure 1**). The main idea in the second budget period is to apply conventional technology to develop a reservoir management plan. Unlike the first budget period, where modern technologies such as micro-resistivity logs and cross borehole tomography data were collected, in the second budget period, the analysis relied on more conventional data. Any use of modern technology was restricted to the analysis and interpretation of the data.

In addition to the existing logs and core data, six new gamma-ray logs were acquired to compliment the existing data. There was a suspicion that the upper structure may have developed a secondary gas cap. To check this, three cased-hole neutron logs (TDT) were conducted. No evidence of secondary gas cap was observed.

Since it was difficult to study all parts of the reservoir in great detail, we graded the reservoir based on a method of potential index mapping. This mapping involves evaluating various areas in the reservoir based on the permeability, thickness, porosity, and saturation as well as prior access to that area by already existing wells. A reservoir with high conductivity and high storativity is given a high productivity index. Depending on whether the area of interest is drained by already existing wells, a potential index is calculated. A region with a high potential index is investigated further, whereas a region with a low potential index was eliminated from further consideration. In addition to potential index mapping, we also examined the primary and secondary recovery production from various units. Based on the grading of various parts of the reservoir, we high-graded certain areas of the field.

We investigated various scenarios for improving the performance of the high-graded areas. For one area, we observed that drilling of a deviated producing well will result in the most improvement in the production. For other areas, we observed that recompletion and stimulation of upper intervals will result in the most improvement in the production.

Based on our evaluation, we decided to drill a deviated well, which would be completed in the upper and middle part of the Glenn sand. The deviated producing well will be supported by three injectors: one in the north and two in the south. To achieve the drilling in a cost-effective manner, we employed a relatively new technology of surface steered drilling, which is much cheaper than conventional deviated-hole drilling. Unfortunately, drilling of a deviated hole proved to be much more challenging than anticipated. We lost the drilling assembly twice. During the second time, we could not fish it, and the hole had to be abandoned. As a result, our reservoir management plan during the second budget period could not be validated. Because of budget constraints, another attempt at drilling a deviated hole could not be made. Hopefully, private owners will take the initiative and, with favorable oil prices, drill deviated wells in the same field to validate the concept.

SUMMARY

Looking back at the project, we can conclude that, although the project ended on a sour note, we were able to demonstrate that cost-effective technologies can be used to improve the performance of marginal oil fields. We evaluated various technologies and determined their cost-effectiveness for future use. We also demonstrated the usefulness in describing the reservoir using integrated information so that we will be able to better predict the future performance of the reservoir. The success is further satisfying by the fact that Glenn Pool Field is 90 years old. If we can demonstrate that the field can be rejuvenated with cost-effective technologies, there are many younger fields where the technologies would be much more useful.

REFERENCES

1. Kuykendall, M. D., and Matson, T. E.: "Glenn Pool Oil Field, Northeast Oklahoma Platform," American Association of Petroleum Geology - Treatise of Petroleum Geology Atlas of Oil and Gas Fields: Stratigraphic Traps III, pp. 155-188 (1992).

2 Kelkar, M., Kerr, D. and Liner, C.: "Integrated Approach Towards the Application of Horizontal Wells to Improve Waterflooding Performance", Final DOE Report under Contract No. DE-FC22-93BC14951 (September, 1999).

Reservoir Class Field Demonstration Program

Class Revisit Awards announced October 5, 1999

Winners of the Class Revisit solicitation were selected from twenty-seven proposals received by DOE. The ten projects selected will share $23 million in Federal money and have agreed to contribute an additional $46 million of their own funds to complete the projects. Projects were selected in all three Class I, II, and III reservoirs and in both light and heavy oil. Secretary Of Energy Richardson reaffirmed DOE's commitment to small independent oil producers, which "now account for nearly half of the oil produced in the lower 48 states." Twenty-three independent oil producers, consultants, and service companies are involved in the projects, which include five projects headed by independents. Contracts are currently being finalized and work will start early in 2000.

The Winners Are!

University of Alabama - Tuscaloosa, AL - Multidisciplinary study of the Womack Hill oil field in Choctaw and Clarke Counties, Alabama, using reservoir characterization, data integration, and advanced seismic, drilling and other technologies to improve oil flow through the reservoir and extend the productive life of the field. The researchers will also apply a variation of a microbial recovery process, termed "immobilized enzyme" technology.

The University of Alabama contact is Dr. Ernest Mancini, 205-348-4319.

Project Team: University of Alabama, Pruet Production Company, University of Mississippi, Mississippi State University, Wayne Stafford & Associates, Texas A&M University.

Project Title: Improved Oil Recovery from Upper Jurassic Smackover Carbonates Through the Application of Advanced Technologies at Womack Hill Oil Field, Choctaw and Clarke Counties, Alabama, Eastern Gulf Coastal Plain (Class II Reservoir).

Ensign Operating Company - Denver, CO - Advanced seismic characterization of variations and compartmentalization in reservoir rock to identify optimal fluid flow paths that operators can use to improve waterflood sweep efficiency in the Eva South Unit, Texas County, Oklahoma.

Ensign Operating contact is David Wheeler, 303-293-9999.

Project Team: Ensign Operating Company, Western Geophysical, Miller Consulting Services

Project Title: Advanced Reservoir Characterization and Development Through High-Resolution 3C3D Seismic and Horizontal Drilling: Eva South Morrow Sand Unit, Texas County, OK (Class I Reservoir).

Michigan Technological University - Houghton, MI - Apply advances in 2-D seismic, geochemical, horizontal drilling and logging technologies to obtain detailed descriptions of reservoir conditions that can facilitate recovery of new and bypassed oil in the Vernon Field, Isabella County, Michigan.

Michigan Tech contact is Dr. James R. Wood, 906-487-2531.

Project Team: Michigan Technological University, Western Michigan University, Cronus Exploration Co., LLC.

Project Title: Using Recent Advances in 2-D Seismic Technology and Surface Geochemistry to Economically Redevelop a Shallow-Shelf Carbonate Reservoir, Vernon Field, Isabella County, MI (Class II Reservoir).

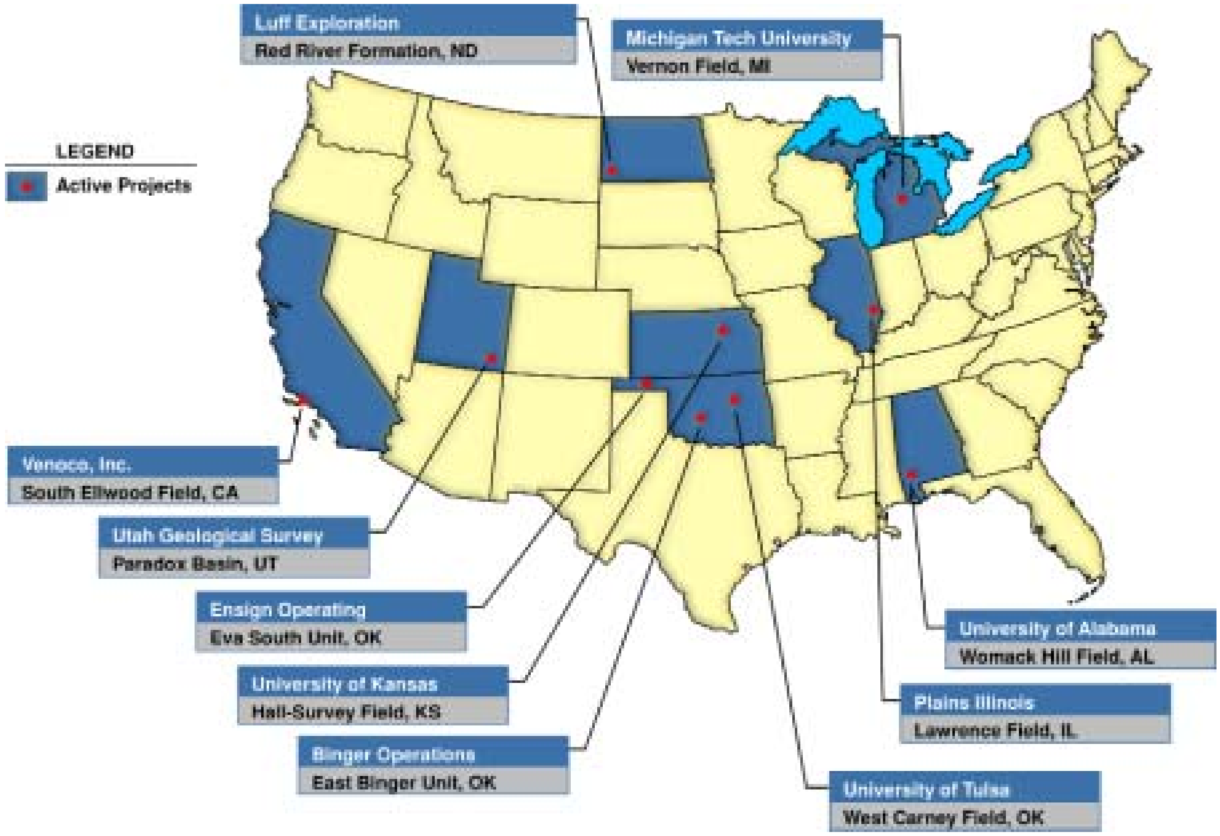
Luff Exploration Company - Denver, CO - Intelligent computing system to establish relationships between seismic, production, and geological data in the Red River Formation, Bowman County, North Dakota, to locate optimal drilling targets.

Luff Exploration contact is Kenneth D. Luff, 303-861-2468.

Project Team: Luff Exploration Company, Energy & Geoscience Institute, Mark Sippel Engineering, Inc., Avalon Consulting, Inc.

Project Title: Intelligent Computing System for Reservoir

CLASS REVISIT AWARDS



Analysis and Risk Assessment of Red River Formation, Williston Basin, North Dakota (Class II Reservoir).

Binger Operations - Oklahoma City, OK - Assess nitrogen flooding as a recovery process in the East Binger Unit, Caddo County, Oklahoma, and combine detailed reservoir description and computer simulation to locate horizontal wells that can improve nitrogen flood performance by reducing gas breakthrough and cycling.

Binger contact is Teresa Muhic, 307-587-2445.

Project Team: Binger Operations, LLC, Canyon Oil & Gas Company, International Reservoir Technologies, Inc.

Project Title: Improved Miscible Nitrogen Flood Performance Utilizing Advanced Reservoir Characterization & Horizontal Laterals in a Class I Reservoir – East Binger (Marchand) Unit (Class I Reservoir).

Venoco, Inc. - Santa Barbara, CA - Determine the nature of the field-wide fracture patterns and the reservoir fluid flow system in the California offshore South Ellwood Field for optimal location of new wells and downhole water separation units that can reduce water disposal costs by controlling aquifer inflow.

Venoco contact is Gary Orr, 805-884-7460.

Project Team: Venoco, Inc., University of Southern California, Baker-Hughes-Centrilift, Schlumberger, Inc., Dynamic Graphics (Class III Reservoir).

Project Title: An Advanced Fracture Characterization and Well Path Navigation System for Effective Re-Development and Enhancement of Ultimate Recovery from the Complex Monterey Reservoir of the South Ellwood Field, Offshore California.

The University of Tulsa - Tulsa, OK - Employ core and well log analysis to determine reservoir rock variation and compartmentalization in the West Carney Field, Lincoln County, Oklahoma. The team will assess “huff-n-puff” gas injection techniques as a secondary recovery process and test water production control technologies.

University of Tulsa contact is Dr. Mohan Kelkar, 918-631-3036.

Project Team: The University of Tulsa, Marjo Operating Company,

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James R. Derby and Associates, F. Joe Podpechan, University of Houston

Project Title: Exploitation and Optimization of Reservoir Performance in Hunton Formation, OK (Class II Reservoir).

Plains Illinois, Inc. - Bridgeport, IL - Test alkaline-surfactant-polymer flooding as a means of improving oil production with more efficient, lower-cost flood patterns in the Lawrence Field, Bridgeport, Illinois.

Plains Illinois contact is Philip E. Hart, 618-945-8600.

Project Team: Plains Illinois, Inc., Illinois State Geological Survey, Surtek

Project Title: Alkaline-Surfactant-Polymer Flooding and Reservoir Characterization of the Cypress and Bridgeport Reservoirs of the Lawrence Field (Class I Reservoir).

University of Kansas Center for Research, Inc. - Lawrence, KS - Test CO_2 flooding as a means of increasing production in the Hall-Gurney Field, Russell, Kansas, one of the central Kansas fields whose reservoirs have been depleted by waterflooding.

The University of Kansas contact is Alan P. Byrnes, 785-864-3965.

Project Team: The University of Kansas Center for Research, Inc., MV Energy, LLC, Shell CO_2 Company, Ltd.

Project Title: Field Demonstration of Carbon Dioxide Miscible Flooding in the Lansing–Kansas City Formation, Central Kansas (Class II Reservoir).

Utah Geological Survey - Salt Lake City, UT - Conduct detailed reservoir studies to determine horizontal drilling techniques that can increase well productivity in the Paradox Basin.

Utah Survey contact is Thomas C. Chidsey, 801-537-3364.

Project Team: Utah Geological Survey, Seeley Oil Company, Colorado Geological Survey

Project Title: Heterogeneous Shallow-Shelf Carbonate Buildups in the Blanding Sub-Basin of the Paradox Basin, Utah and Colorado: Targets for Increased Oil Production and Reserves Using Horizontal Drilling Techniques (Class II Reservoir).

Technical Contact for all projects:

Herb Tiedemann, Technology Transfer Manager, National Petroleum Technology Office, 918-699-2017, tiedema@npto.doe.gov.

The *Class* Act

The *Class* Act is a biannual newsletter devoted to providing information about **DOE's Reservoir Class Program**.

For more information on Class Program projects, contact **Herb Tiedemann** at **DOE's National Petroleum Technology Office**:

Ph. 918-699-2017
Fax 918-699-2005

You may also contact **Viola Rawn-Schatzinger**.

Ph. 918-699-2018
Fax 918-699-2005

Editor: *Viola Rawn-Schatzinger, RMC, Inc.*
Copy Editor: *Michael Blechner, SCG, Inc.*
Graphic Designer: *Kristi Lovendahl, SCG, Inc.*

If you have a project that you would like to preview in an issue of **The *Class* Act** please contact Viola Rawn-Schatzinger.

INDEPENDENT HIGHLIGHTS

By Viola Rawn-Schatzinger, RMC, Inc.

In DOE's Field Demonstration Program, the projects fall under the Reservoir Class Program and the Petroleum Technology Advances through Applied Research by Independent Oil Producers. The Independent projects are much shorter term and less have less funding than the Class Projects. Independent projects are funded by DOE to attempt to solve one particular problem. The purpose is to help small independent producers test technologies of interest to them which would benefit others by meetings one or more of NPTO's goals: 1) extending reservoir life, 2) increasing production or reserves, 3) improving environmental performance, 4) broaden the exchange of technology information. Twenty-two Independent projects have been completed (**Figure 1**). The chart shows the breakdown of projects relative to technological and economic success.

The new Independent Highlights section of *The Class Act* will provide information on completed independent projects and summarize ongoing project results and lessons learned. The twenty-two recently completed projects were in twelve states and cost a total of $3.5 million, with $1.0 million (29%) provided by DOE and $2.5 million (71%) from the independent operators. Various projects will be featured in future newsletters. Information on new projects will be summarized in the next DOE *Inside Technology Transfer* newsletter.

HIGHLIGHT: COBRA OIL & GAS TUSCALOOSA, ALABAMA

Cobra Oil & Gas in conjunction with the University of Alabama performed on whole core and FMI log analysis study on the Frisco City Sandstone in Monroe County, Alabama, to test the economics of FMI log interpretation as alternative to coring. Schlumberger's Formation Micro-imaging (FMI) log was run in a Frisco City well for which whole core was available for comparison. The complete core description was compared to the FMI log interpretation to determine if the FMI log can be used as a less expensive and less risky means to determine the facies and reservoir characteristics.

The results of the FMI and core analysis comparison showed that the environment of deposition interpretation did not differ significantly. The FMI log provided data on paleocurrent direction and sandstone orientation not available from core description. This additional data is critical to establishing a regional reservoir stratigraphic model. The FMI log also identified anisotropic features, which could be barriers to fluid flow.

The comparison between whole core analysis and FMI log interpretation from the Frisco City well indicated that the FMI log could be a valid alternative to obtaining whole core. The cost savings were estimated at from $10,000 to $25,000 per well in the southern Alabama area depending on depth and conditions. Typical coring costs in the area run $20,000 per well, and FMI costs were estimated at $5,000 per well.

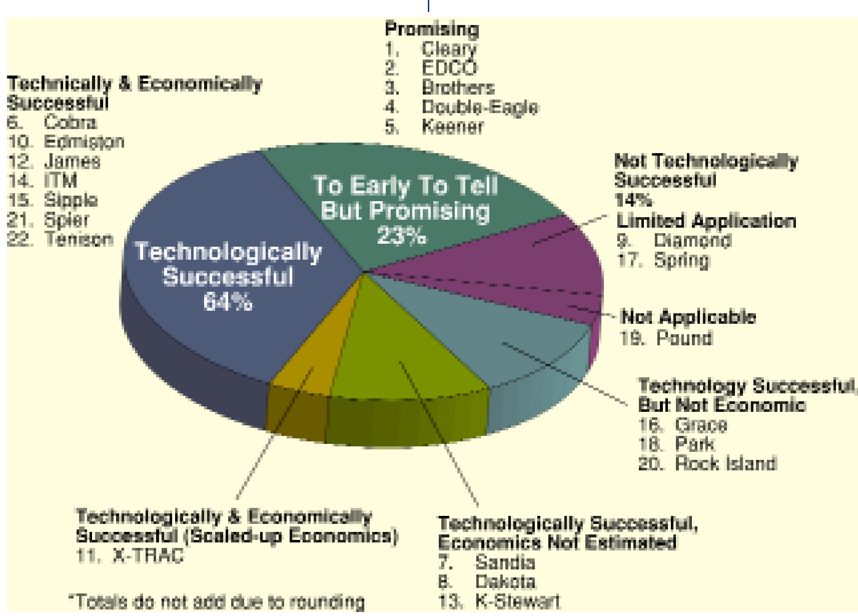

Figure 1 The majority of 22 projects by Independents were successful.

C A L E N D A R

Presentations

Southwest Section AAPG–Dutton, S. "Characterization of reservoir heterogeneity in slope and basin clastic reservoirs, Bell Canyon Formation, Delaware Basin, Texas," Midland, Texas, February 28-29, 2000. (Class III 14936)

Kansas Geological Society Annual Meeting–Gerlach, Paul, "Horizontal Drilling in Kansas: current status and case histories": Lawrence, KS, March 9, 2000. (Class II 14987)

SPE/DOE IOR Symposium–Weinbrandt, R. M., "Case History of Waterflood Optimization: Grayburg Reservoir in the Foster–South Cowden Field": "IOR Oil Odyssey 2000": Tulsa, OK, April 2-5, 2000. (Class II 14982)

AAPG National Convention–New Orleans, LA, April 16-19, 2000

- Chidsey, T. C., Jr., D. E. Eby, "Facies of the Paradox Formation, southeastern Utah, and modern analogs: tools for exploration and development". – Poster. (Class II 14988)
- Gerlach, P. M., S. Bhattacharya, T. R. Carr. "Cost-effective techniques for the independent producer to evaluate horizontal drilling candidates in mature areas." (Class II 14987)

Announcements

SPE / DOE Twelfth Symposium on Improved Oil Recovery, "IOR Oil Odyssey 2000": Tulsa, OK, April 2-5, 2000. Contact Betty Felber (918) 699-2031.

DOE/FE Sponsored Alaska Workshop, Anchorage, AK, Topics on Artic Practices, April 25-26, 2000. Contact Rhonda Lindsey (918) 699-2037.

Bureau of Indian Affairs, "National Indian Energy & Minerals Conference", Golden, CO, March 28-30, 2000. DOE/NPTO is sponsoring a half-day workshop on March 30, 2000. Contact Steve Manydeeds (303) 969-5270.

Pacific AAPG/SPE Western Regional, Long Beach, CA, June 19-22, 2000. Contact Don Clarke (562) 570-3915.

HERB TIEDEMANN
DEPARTMENT OF ENERGY
NATIONAL PETROLEUM TECHNOLOGY OFFICE
P.O. BOX 3628
TULSA, OK 74101-3628